The Role of Biomass in the Renewable Energy System

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Abstract:

Europe is striving for zero carbon electricity production by 2050 in order to avoid dangerous climate change. To meet this target a large variety of options is being explored. Biomass is such an option and should be given serious consideration. In this paper the potential role of biomass in a NW-European electricity mix is analyzed. The situation in NW-Europe is unique since it is a region which is a fore runner in renewable technology promotion but also an area with little sun, almost no potential for hydro and a lot of wind. This will result in a substantial need for non-intermittent low-carbon options such as biomass. The benefits and issues related to biomass are discussed in detail from both an environmental and an economic perspective. The former will focus on the life cycle of a biomass pellet supply chain, from the growth of the trees down to the burning of the pellets on site. The latter will provide detailed insights on the levelized cost of electricity for biomass and the role of biomass as a grid stabilizer in high intermittent scenarios. During the discussion, biomass will be compared to other competing electricity technologies to have a full understanding of its advantages and drawbacks. We find that biomass can play a very important role in the future low carbon electricity mix, the main bottleneck being the supply of large amounts of sustainably produced feedstock.

Keywords:

Biomass, Renewable Energy, Sustainability, Economics, Learning Rate.

1. Introduction

Biomass as a renewable energy source has been used by humans for many centuries. Today, it is still a very important source of energy in developing countries. In 2011, biomass had a share of about 10% in global energy demand, however, only a small amount of biomass is used for electricity production. Globally, about 62 GW of biomass power capacity was estimated to be installed by the end of 2010. This is slightly higher than the installed capacity of PV, but significantly smaller compared to global wind capacity (1). In the EU-27, biomass has been used for energy purposes for a long time, mainly by Scandinavian countries. Today, Sweden and Finland together account for 18.4 TWh of electricity production from solid biomass, namely 30% of the total EU-27 solid biomass electricity production. This is almost entirely due to the use of CHP plants (17.5 TWh)(2). Similarly, other countries are now looking at biomass technology too, in order to reach their renewable energy targets imposed by the European commission (3). Especially countries like Belgium, the Netherlands, Germany and the U.K. are trying to tap into this energy source for renewable electricity production. Together, these four countries produced 21.1 TWh of electricity from solid biomass in 2009, which is about 34% of the total amount of solid biomass electricity production in the EU (2). Unlike the Scandinavian countries, NW-European (NW-E) member states mainly use biomass for “electricity-only” purposes (15 TWh), in increasingly larger power plants.

Despite the growing interest by governments to use biomass for electricity production in large scale power plants, the scientific world has not focused much on this subject. Most literature is targeting biomass use for transport (4-6). Authors that did focus on the use of biomass for electricity production have often only considered small scale installations, mainly CHP (7-9), which is not so common in NW-E. Furthermore, most papers limit the analysis to the environmental implications of biomass use (5, 10, 11), and neglect economic aspects.

This paper aims to assess the potential role of large scale biomass pellet power plants in NW-E from an environmental and economic perspective. The environmental assessment is based on the Life Cycle Assessment (LCA) methodology. For the economic analysis, the Levelized Cost of Electricity (LCOE) methodology is applied to evaluate the cost competitiveness of the technology. Finally, the potential of biomass electricity as a backup for variable renewables in the electricity mix is studied.

Most of the data, such as energy prices and investment costs, on which the assessments in this study are based, were obtained from a combination of a vast literature review and long discussions with the industry. In the first part of this paper, the environmental impact of biomass use will be discussed. The second part will consist of the economic analysis. We will conclude with an overall discussion on the implications of increasing the role of large scale biomass in the future electricity mix in NW-E. Even though this study is focusing on NW-E, the findings can be interesting for policymakers, energy companies and investors worldwide.

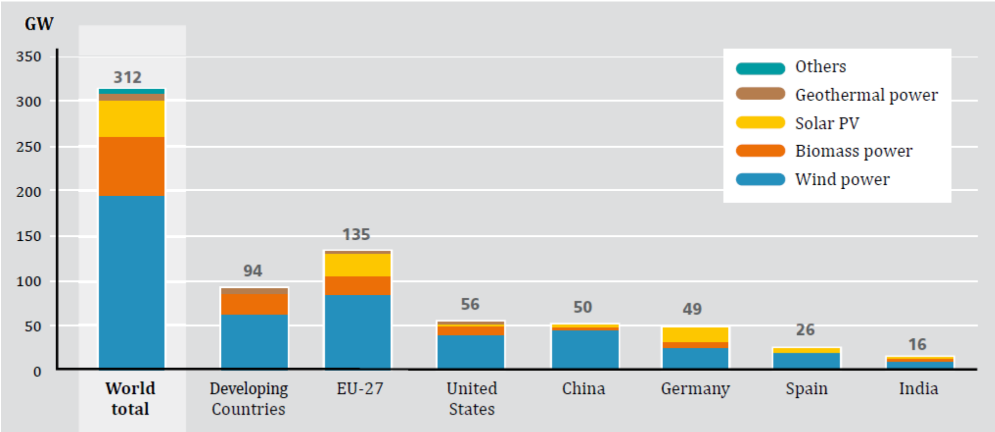

Figure 1: Renewable capacity; globally, in developing countries, the EU-27 and top 5 regions (1)

2. Environmental analysis

2.1. Introduction

A life cycle assessment (LCA) is considered to be the most comprehensive and credible method to evaluate the environmental impact of a good or service. In an LCA the whole lifecycle of a technology is considered. Many scientists have used the LCA methodology to evaluate the environmental impact of renewable and non-renewable energy technologies (5, 12-17). The lifecycle of an energy technology typically consists of construction, fuel use, operation and maintenance (O&M) and decommissioning. Various perspectives such as land use change, water use, mineral extraction, energy use and human health can be included in an LCA (18). However, due to increasing concerns about climate change, current research is mainly focusing on greenhouse gas (GHG) emissions (17, 19-21).

Recently, biomass has received a lot of attention and is widely considered to be an essential part of the sustainable or “green” economy (22, 23). This growing interest is unfortunately matched by a rise in criticism. The impact of the development of a bio-based economy on the environment in general, and on land use and food prices in particular is causing great concern (24). This resulted in an abundance of studies that have primarily shown that the afore-mentioned issues are complex and the sustainability of biomass strongly depends on specific circumstances (5, 14, 18).

The debate on the merits and problems surrounding biomass benefits from improved knowledge on the life cycle of biomass in the green economy. LCAs can provide important insights in the environmental impact of a biomass energy chain and help locate the most critical steps in that chain. This information should help developers and policymakers to increase the sustainability of biomass production and its use, and to possibly overcome some of the current issues. This study will focus specifically on the life cycle of large scale (> 300MW) biomass power plants in NW-Europe using Canadian wood pellets.

2.2. Methods

The environmental impact of biomass usage for energy purposes has been studied extensively. Unfortunately, assumptions regarding type of biomass, land use change, fertilizer usage, pesticide usage, transport and final combustion technology vary immensely (18). It is thus difficult to find studies that focus specifically on the life cycle of large scale combustion plants using pellets. In fact, only one such paper was found in the literature (25). The main steps of the biomass life cycle are shown in Figure 1. Each of these steps will be described in more detail below (see next paragraph "The NWE Case").

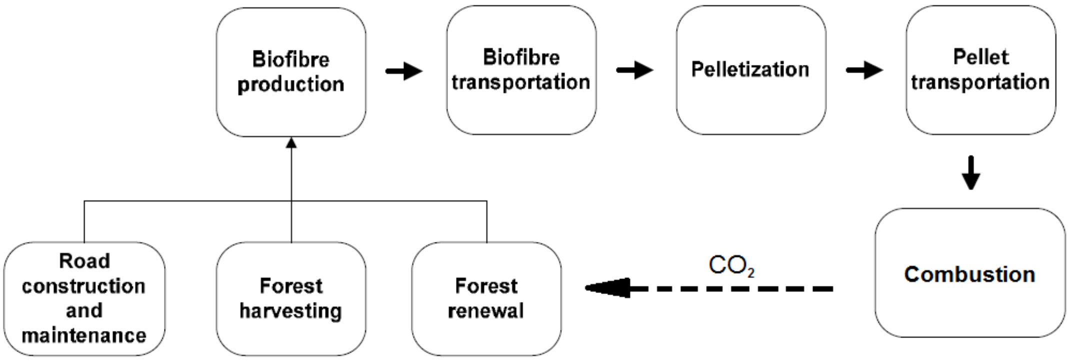

Figure 2: Boundaries of the large scale biomass lifecycle (based on Zhang et al. 2010)

An assumption which is crucial for this LCA is that the wood from Canadian forests is sustainably grown which allows us to state that the emission of GHGs at the plant site are balanced by the uptake of GHGs in the growth phase of the biomass. In other words, the net GHG emissions are considered to be equal to zero. We chose not to consider the possible effects of biomass production on land use or on carbon stocks, even though these two aspects could have a very big influence (14, 18, 26, 27). It is therefore important to note that if the sustainability assumption does not hold, the results presented below will not be valid. If not sustainably produced, the use of biomass is neither environmentally nor socially desirable.

2.2.1. The NW-European Case

In order to fit with a NW-European situation, we adapted the data from the literature (25). To this end, we split up the biomass pellets production chain into four phases:

1. Harvest and pellet production in Canada
2. Transport from pellet plant to harbour in Canada
3. Transport from harbour in Canada to a harbour in NW-Europe
4. Burning of pellets in a NW-European biomass plant

GHG and NOx emissions were calculated in every phase and adapted to the NW-European situation if needed. The harvest and pellet production phase were assumed to be similar. Also, the transport distance from pellet plant to harbour is likely to be in the same range as the transport distance from the pellet plant to a power plant (+/- 1000 km by train or boat, comparable to the 750 km by train estimated by industry). In other words, we made no changes in phases one and two, but, from the third phase onwards, the data was adapted. In phase three, the emissions during transport from Canada to NW-Europe were calculated for a distance of 3500 miles (+/- 6000 km). GHG and NOx emissions due to this transport are considered to be around 5.89-12.5 g/(ton*mile) and 0.22-0.36 g/(ton*mile) respectively (21, 28). Finally, in phase four, NOx emissions from the NW-E power plant were estimated to be equal to the European limit for new large scale biomass power plants (>300 MW), namely150 mg/Nm³ at 6% O_2, or 0.55 g/kWh (29). The GHG emissions on site are considered to be compensated by the growth of new biomass, and thus they were assumed to be zero.

2.3. Results and Discussion

2.3.1. Biomass plants in NW-Europe

The results in Figure 3 show that total life cycle GHG and NOx emissions for a NW-E biomass pellet plant are estimated to be 109.5 and 1.6 g/kWh respectively. Focusing on GHG emissions, we find that the majority is released during the growth, harvest and pellet production phase in Canada. GHG emissions related to Canada/NW-E sea transport are relatively low. As mentioned above, GHG emissions on site are assumed to be equal to zero. Unsustainable forestry practices could however result in GHG emissions exceeding 300 g/kWh (18).

For NOx emissions, things are very different. These are emitted in every step of the production chain, in relatively equal amounts. Pellet production accounts for 32% of the total NOx emission, sea transport for 33% and on site emissions account for the remaining 35%. Be aware that NOx emissions on site are assumed to be equal to the European emission limit value (0.55 g/kWh). Since this is a legal upper limit, it is very likely that these emissions will be lower in practice. One should also keep in mind that individual member states, or regions, can have lower emission standards than those imposed by the EU. In Flanders, for example, the NOx norm for large scale biomass plants is 90 mg/m³ at 6% O_2, or 0.33 g/kWh. In other words, a Flemish biomass power plant would have NOx combustion emissions below 0.33 g/kWh. Therefore, the NOx emissions presented here are considered to be an upper limit for NW-Europe.

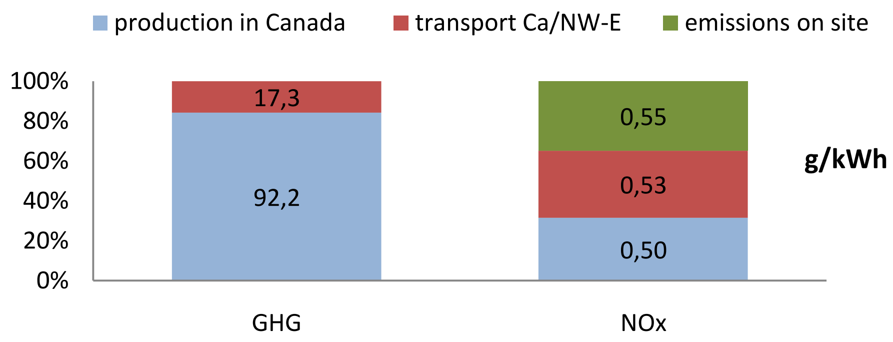

Figure 3: Estimated GHG and NOx emissions for a NW-E biomass plant fired with Canadian pellets (calculations based on (21, 25, 28, 29))

2.3.2. Literature review

The results in Table 1 present recent findings in LCA literature. The data contains a mix of both old and new technologies currently used in developed countries (EU, N-America). The "NW-E biomass plant" case is, however, an exception as this refers to a specific type of biomass power plant, subject to European NOx emission laws. In other words, the table indicates how GHG and NOx emissions of a new biomass power plant (including the biomass life cycle) differ from average power plants and other energy technologies currently in operation.

2.3.2.1 Combustion emissions

The GHG combustion emissions from an average gas fired power plant and coal plant are around 400 and 950 gCO_2-eq/kWh respectively, which is much higher than biomass combustion emissions, since the latter are assumed to be zero. Focusing on NOx, we find that the NW-E biomass plants have NOx emissions of only (maximum) 554 mg/kWh, which is considerably lower than emissions coming from average coal or gas fired power plants. However, new coal plants in the EU will also be subjected to the EU norm of 150 mg/Nm³ at 6% $O_{2,}$ gas plants will even have lower norms (100 mg/Nm³ at 6% O_2).

2.3.2.2 Life cycle emissions

For gas and coal, lifecycle GHG and NOx emissions are similar to combustion emissions[1] (Table 1). In the case of biomass this is quite different; life cycle emissions for biomass are markedly higher than combustion emissions. Nevertheless, over the whole lifecycle, biomass power plants emit less GHG compared to coal and gas. For life cycle NOx emissions, biomass is similar to gas, but much lower than coal.

The last row of Table 1 shows the estimated results for a future coal powered plant (2025) with CCS technology. According to the literature (21), current biomass technology emits less GHGs than possible future CCS technology, while NOx emissions are similar. However, by 2025, better NOx removal technology could be in place for biomass too, which is likely to result in NOx emissions lower than coal + CCS.

Compared to PV technology, biomass emits similar amounts of GHGs over its lifecycle, although the NOx emissions of PV-systems are significantly lower. Overall, wind onshore and offshore emit the lowest amount of polluting substances during the entire life cycle of all the energy technologies considered here.

Table 1: Combustion and LCA emissions for GHG and NOx of various energy technologies (5, 10, 17, 18, 21, 25, 30-37)

Combustion emissions							
		GHG (g/kWh)			NOx (mg/kWh)		
		min	average	max	min	average	max
100% biomass	*New >300 MW (NW-E)*		*0*			*554*	
Gas		318	454	636	54	1208	2361
Coal	no CCS (today)	780	953	1044	1162	2642	4122

Life Cycle emissions							
		GHG (g/kWh)			NOx (mg/kWh)		
		min	average	max	min	average	max
100% biomass	Mixed types	2	66	122	781	923	1064
	Canada pellets		92			1000	
	New >300 MW (NW-E)	*103*	*110*	*116*	*1473*	*1587*	*1702*
PV		50	99	160		340	
Wind	onshore	4	17	40		31	
	offshore	9	13	17		21	
Gas		360	466	720	77	1782	4268
Coal	no CCS (today)	800	1024	1800	1285	2842	4399
	with CCS (2025)	130	190	280	863	1251	1639

2.3.2.3 Particulate Matter

The emission of fine dust particles (particulate matter or PM) is an important issue from a human health perspective, which is, unfortunately, not well documented in LCA literature. A recent report by Greenpeace (2011) indicated that PM combustion emissions from biomass power plants (560 mg/kWh) are higher than PM released by fossil-based technologies, such as coal, gas or oil. However, it is important to keep in mind that their data are only valid for small scale biomass power plants (<70 MW), which typically use relatively inefficient flue gas filtering technologies. These emissions can be reduced drastically by using the most advanced equipment.

[1] For LNG gas this is different, since a lot of energy is needed for compression/transport/decompression

The upper limit of dust combustion emissions for large scale biomass plants in Europe can be calculated starting from the legal PM-emission limit which is 20 mg dust/Nm³ at 6% of O_2, or about 67 mg/kWh (29). This is considerably lower than the emissions mentioned in the Greenpeace report. Furthermore, since 20 mg dust/Nm³ at 6% of O_2 is the legal limit in the EU, we can safely state that in practice emissions are likely to be lower than 67 mg/kWh. However, over the whole lifecycle the dust emissions will be higher, especially due to transport by truck and ship.

2.4. Conclusions

In general, considering GHG and NOx emissions, biomass is more environmentally friendly than coal or gas. However, this statement is only valid if the biomass is produced sustainably. If this is not the case, GHG and NOx emissions can be much higher than presented here. When compared to other renewables, biomass appears to have a relatively high impact on the environment. The life cycle GHG emissions of biomass are comparable to those of PV systems but about a tenfold higher than the amount of GHGs emitted when using wind energy. The results for NOx are even worse, with biomass releasing roughly five times as much as PV and 50 times more than wind. However, some issues should be kept in mind. Firstly, the environmental impact of biomass could decrease if power plants became more efficient or transport was organized in a more sustainable way. Secondly, comparing biomass to intermittent renewables is not really fair, since the latter will not be able to achieve high penetration as long as cheap storage technology is unavailable. Biomass LCAs should be considered from a holistic, system wide perspective. Unfortunately, this is far from easy since the specific properties of the electricity infrastructure need to be taken into account.

Finally, it should be stressed that the scope of this study is rather limited. Other important aspects of the environmental impact of the power technologies would also be interesting to compare. Data on life cycle particulate matter emissions, fossil fuel depletion or energy efficiency would result in a broader understanding of the environmental impact of biomass electricity production. Unfortunately, data on these issues is currently not available for large scale biomass power plants. Further research is necessary to have a better understanding of all the steps in the whole lifecycle and how these affect the environment.

3. Economic analysis

When comparing energy technologies many criteria need to be considered. For example, the type of demand for which new capacity is needed – base, intermediate or peaking load – will determine the most economically effective technology to supply electricity. Electricity might be a standardized commodity, behind it lays a segmented supply side, with each segment functioning on different economic parameters. Due to the expected growth of intermittent generation, the boundaries between the different demand types will become less explicit in the coming years and many assets will have multiple load purposes (even during one single day).

3.1. Levelized Cost of Electricity (LCOE)

3.1.1 Introduction

The LCOE (levelized cost of electricity) methodology is an interesting tool to compare the cost of producing a unit of electricity with various technologies. According to the International Energy Agency “LCOE remains the most transparent consensus measure of generation costs and remains a widely used tool for comparing the costs of different power generation technologies in modelling and policy discussions” (38). The levelized cost of electricity (LCOE) represents the present value of the total costs of building and operating a generation plant or a generation asset over its financial life. In principle, the LCOE is calculated for *new* generation assets. As a consequence, the production cost per MWh of *existing* assets should not be compared to LCOE results, as the investment cost per MWh is not included.

However, the LCOE methodology has some limitations; as it does not evaluate the aspect of risk, which is very important when taking investment decisions, in addition, it looks at the different technologies from a "stand alone" perspective. The LCOE is calculated at the plant level and excludes system costs and system externalities. The latter factor is a major issue for variable (non-dispatchable) renewable energy technologies (38) because demand and supply need to be balanced literally every second. Basically, direct system costs should be added to the plant-level LCOE of all technologies but this proves to be very challenging. In order to overcome this issue, a broader, system-wide, economic assessment will complement the LCOE analysis (see section 3.2).

Finally, the LCOE should be interpreted as a social cost or the cost for society of building and operating the generation plants. The financial impact of taxes, subsidies, portfolio standards or other incentive schemes is therefore not considered. In this section, eight technologies will be compared: 100% biomass using pellets, biomass co-firing (50% co-firing, see Appendix A), PV, wind onshore, wind offshore, coal, nuclear and gas.

3.1.2. Methodology

3.1.2.1. LCOE calculation

The LCOE takes into account the annualized investment cost, the operation and maintenance (O&M) cost, fuel cost and carbon cost:

$$LCOE = I + O\&M + F + C \tag{1}$$

With I = annualised investment cost [EUR/MWh]
O & M = operation and maintenance cost [EUR/MWh]
F = fuel cost [EUR/MWh]
C = carbon cost [EUR/MWh]

And

$$I = Itot / \left(AF_i^n \cdot FLEOH \right) \tag{2}$$

With Itot = total investment cost/MW [EUR/MW]
AF_i^n = annuity factor
FLEOH = full load equivalent operating hours [h]

The annuity factor for a given lifetime and discount rate has been calculated as follows[2]:

$$AF_i^n = [1 - (1 + i)^{-n}]/i \tag{3}$$

With n = lifetime
i = discount rate

The assumptions regarding fuel cost, lifetime and O&M costs are based on data found in the literature and discussions with the industry. They can be found in Appendix A.

Essential for estimating the full load equivalent operating hours (FLEOH) is the load factor (LF). This indicates the percentage of time that a technology produces electricity at maximal capacity. It shows how much electricity can be produced with an installation of a certain capacity in one year.

$$LF = \frac{FLEOH}{24h \cdot 365d} \tag{4}$$

With LF = load factor [%]
FLEOH = full load equivalent operating hours [h]

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[2] Annuity factor is commonly used to calculate the present value of future series of cash flows (Richard et al, Quantitative Investment Analysis, 2007).

Unlike fossil fuelled technologies, renewable intermittent technologies such as wind and PV have the disadvantage of only producing electricity when the weather is favorable. Luckily, the NW-E region is blessed with respect to wind, having relatively high average annual wind speeds compared to the rest of Europe. Onshore wind turbines operate at full load for about 2200 hours annually (39), which is equal to a load factor of about 25% (2200/24/365 = 25%), offshore wind turbines have higher load factor (35%). For PV, on the other hand, NW-E is not a favorable region. In fact, the LF for PV decreases with declining yearly average solar irradiation. A PV system in London, for example, produces roughly half the amount of electricity compared to a PV system in Malta, for a given capacity (30). Therefore, the LF for a PV system in NW-E is very low (12%). By contrast, the load factor of fossil fuelled power plants is much higher. In this study, the 2012 LFs were estimated to be 85%, 75% and 60% respectively for nuclear, coal and gas.

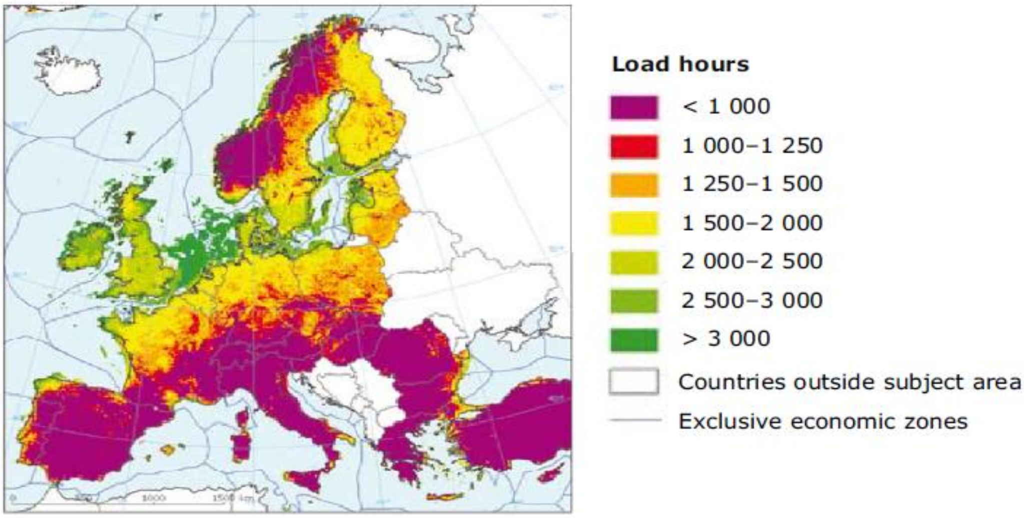

Figure 4: Full load hours for wind turbines in Europe (39)

3.1.2.2 Learning Rate

The economic theory of learning rates (LRs) (40-46) states that due to learning effects the cost of a specific technology will decrease as cumulative production increases according to the following mathematical relationship (based on (47) and (48)):

$$I_t = I_0 \cdot CC^a \tag{5}$$

With I_t = investment cost at time t [EUR/MW]

I_0 = cost of the first unit produced (theoretically) [EUR/MW]

CC = cumulative capacity [MW]

a = learning elasticity

From this the learning rate can be calculated as follows:

$$PR = 2^a \;\; and \;\; 1 - LR = PR \;\;\; thus \;\; LR = 1 - 2^a \tag{6}$$

With LR = learning rate

PR = progress ratio

This formula indicates how the cost will decrease with each doubling of production. For example, if the LR for a given technology is 20% and the installed capacity is 1 GW, the costs are assumed to be 20% lower when capacity has reached 2 GW. The LRs for the various technologies were found in the literature. More information is available in Appendix A.

Although a broad literature on technology learning exists, there is no consensus on the typical and prospective learning rates for the considered generation technologies. However, the learning rates presented here are in line with the literature (49). To address the uncertainty in estimating learning rates, a sensitivity analysis was carried out to illustrate the impact of changes in learning rates.

3.1.2.3. Discount rate

The discount rate reflects the return on capital for an investor in the absence of specific market or technology risks. In the energy sector, relatively high discount rates can be expected due to the uncertain market environment of today with the ongoing liberalization, multiple CO_2 policies, subsidies for new technologies (such as offshore wind and CCS) and the challenge of integrating a growing share of intermittent generation. Furthermore, LCOE methodology assumes a single set of future fuel prices but mostly neglects the impact of higher fuel prices and investment costs (e.g. steel and concrete prices should follow fuel prices). In our calculations, a 10% discount rate was used. This is complemented by a sensitivity analysis with discount rates of 7% and 13%.

3.1.2.4. Fuel and CO_2 prices

The cost evolution of pellets (in bulk) between now and 2030 is probably the most difficult parameter to project. In order to cope with this problem, three pellet price scenarios were evaluated. Next to a standard scenario, with the price of biomass pellets rising at a rate of 1% each year, two other scenarios were added: an optimistic and a pessimistic scenario. In the optimistic scenario, the supply is assumed to be able to keep up with demand and due to improved logistics and better technologies, this would result in a stable pellet price (73 €/MWh), from now to 2030. In the pessimistic case, the supply will have a hard time to keep up with a very sharp increase in pellet demand, resulting in a doubling of the pellet price by 2030. Not surprisingly, the pellet price will have a major impact on the LCOE of a biomass produced MWh of electricity.

Regarding fossil-based technologies, the price of gas and coal is likely to rise with time. Also the CO_2 price is likely to increase between now and 2030. The estimated gas and coal fuel costs were calculated based on the averages of the recent price trends. Biomass pellets costs for 2012 were estimated based on recent literature. However, all the fuels cost estimates have been adapted after discussion with the energy industry. Information on these assumptions can be found in Appendix B.

3.1.3. Results and discussion

The LCOE for the generation technologies between 2011 and 2030 was estimated based on the assumptions found in Appendices A and B. For simplicity the learning rates were kept constant over the period 2011-2030.

3.1.3.1. Standard Scenario

Figure 5 shows the evolution of the LCOE for new generation investments between 2011 and 2030 upon the condition that the load factors in Appendix A are kept stable over the period. Since we assume that fuel costs will increase in the next decades the LCOE of generation technologies depending on fuels (gas, coal, biomass) will increase, with the exception of nuclear for which the fuel cost remains constant along the period. Only the intermittent – fuel free – generation technologies benefit from decreasing investment costs, due to the learning effect. Wind and PV will experience significant LCOE reductions. However, keep in mind that the price of steel and other constructing materials might mitigate the learning effect under certain circumstances and hence reduce the gap between fuel-based technologies and steel-intensive assets.

As illustrated in Figure 5, the LCOE of PV electricity significantly exceeds the cost of other generation technologies. However, by 2030 PV should be close to 120 €/MWh and able to compete with coal, gas and biomass technologies. Keep in mind that we have assumed low irradiation and very conservative learning rates.

In order to provide a better picture of the LCOE for the other technologies, next to Figure 5, we present Figure 6, which is the same figure with the exclusion of PV.

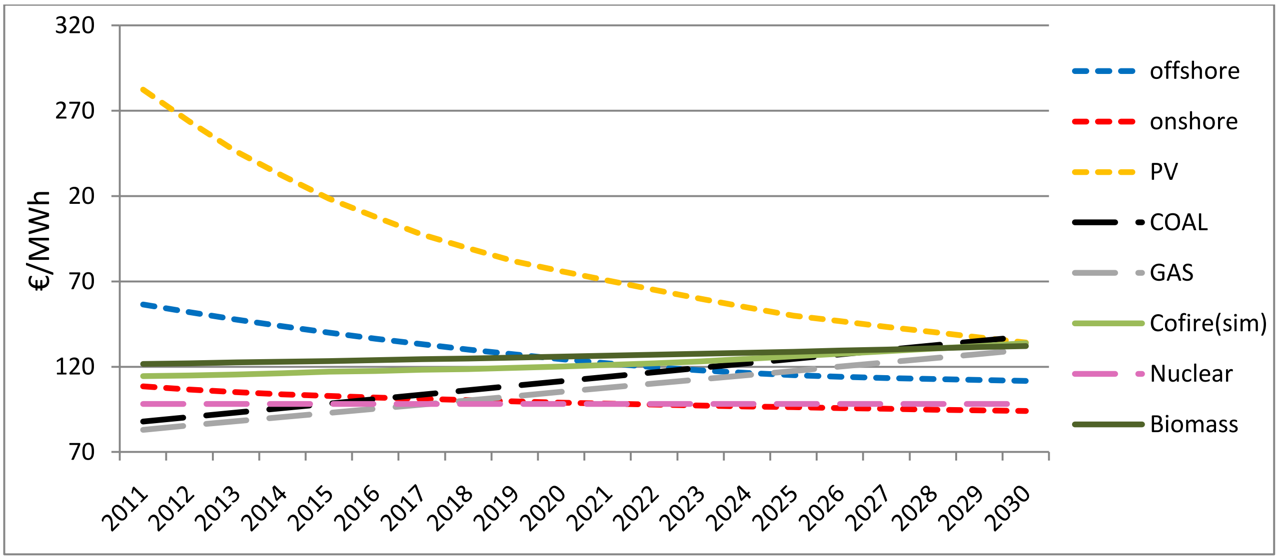

Figure 5: LCOE of new generation assets – standard pellet price scenario

Figure 6 clearly shows that the cost gap between biomass and fossil-based technologies is high in 2012 but declines with time. At the end of the period, the LCOE of biomass is similar to the LCOE of coal and gas. The cost gap between 100% biomass and co-firing is small and decreases over time; by 2030 the LCOE of these technologies is about 132 €/MWh.

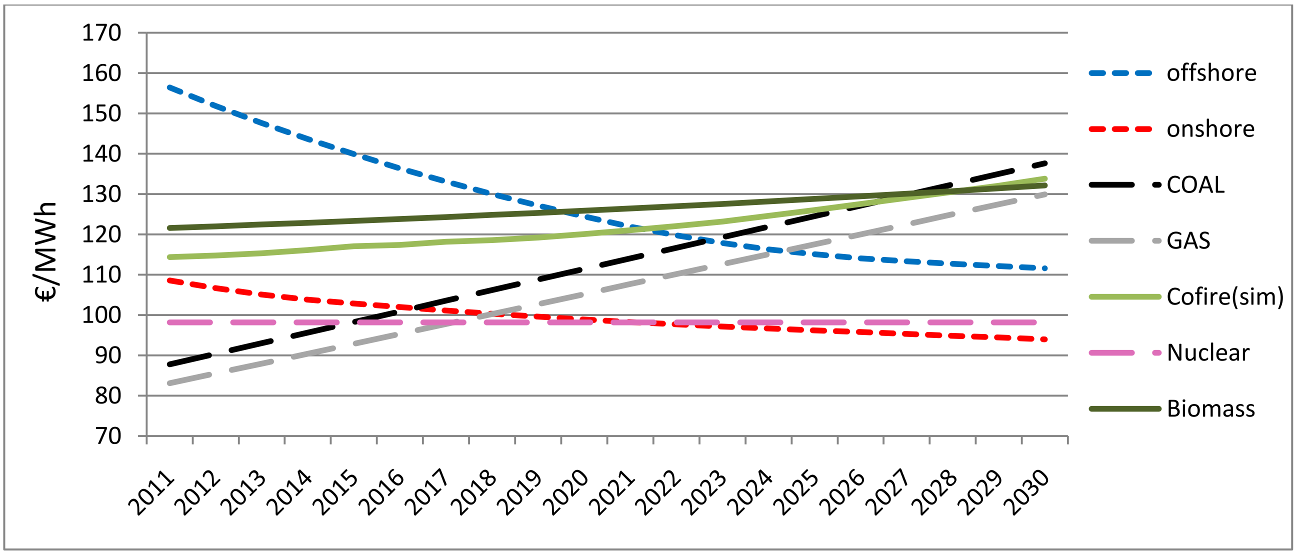

Figure 6: LCOE of new generation assets (PV excluded) – standard pellet price scenario

Since nuclear does not emit CO_2 and uranium prices were assumed to be constant, the cost of nuclear does not evolve in the selected time span, making it one of the cheapest technologies from 2017 onwards. However, from 2022 onwards, the LCOE of wind onshore is lower than the LCOE of nuclear, thus becoming the cheapest technology. Despite having higher investment and maintenance costs, offshore wind benefits from higher load factors than onshore wind (39), also, in this analysis, offshore benefits from the relatively high growth in installed capacity between 2012 and 2030, therefore, due to the bigger learning effect its cost will decrease more than onshore wind.

3.1.3.2. Pessimistic Scenario

Figure 7 presents the results under the assumption that biomass pellet prices double between 2011 and 2030. In this scenario, the LCOE of biomass technologies always exceeds the LCOE of all the non-intermittent technologies.

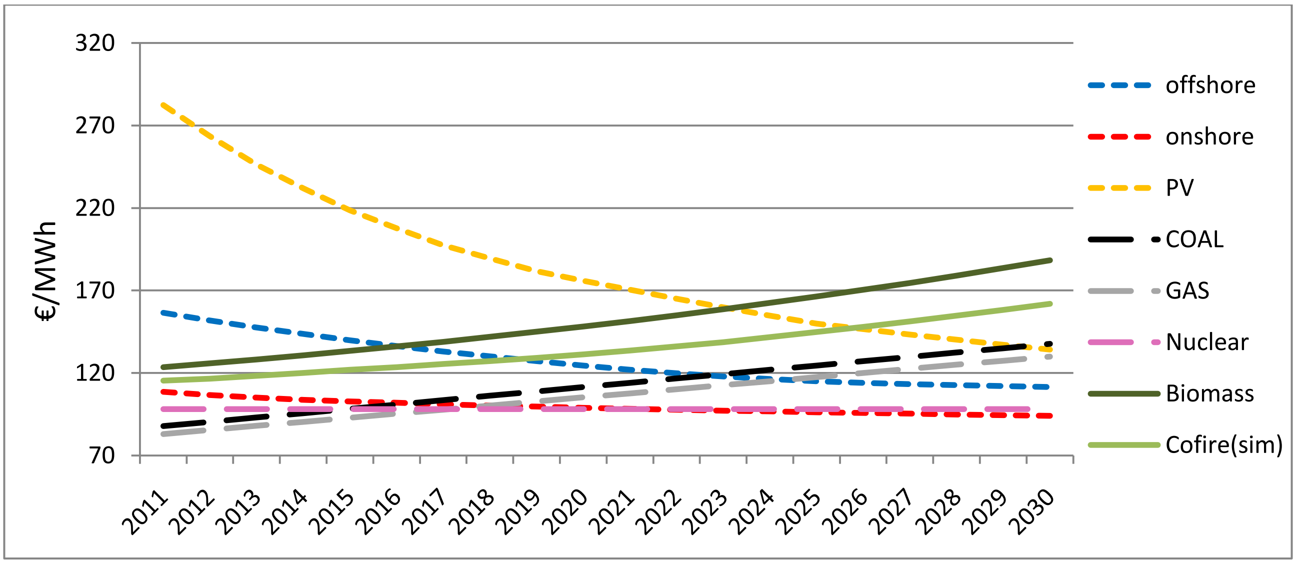

Figure 7: LCOE of new generation assets – pessimistic pellet price scenario

Assuming high pellet prices, the LCOE of the biomass co-firing plant is below the LCOE of the dedicated biomass plant over the whole period, furthermore, the cost gap increases with time, in contrast to the standard pellet price scenario. By 2030, the LCOE of biomass is some 90% higher than the LCOE of wind and nuclear technologies. This means that in case of a considerable pellet price increase, biomass technologies will be uncompetitive compared to the other generation technologies.

3.1.3.3. Optimistic Scenario

Under the optimistic pellet price scenario – with a constant fuel cost for a dedicated biomass plant of 73 €/MWh – the outlook for biomass technologies becomes completely different (Figure 8). In this scenario, biomass technologies become competitive with coal and gas from 2024 onwards. Furthermore, the results in Figure 8 illustrate that in the long term biomass technologies have a lower LCOE then coal, PV and gas. On the other hand, the gap with nuclear and onshore wind remains substantial. The LCOE of co-firing lies above that of biomass from 2023 onwards, but below gas, PV and coal. The latter becoming the most expensive technology from 2030 onwards in this scenario.

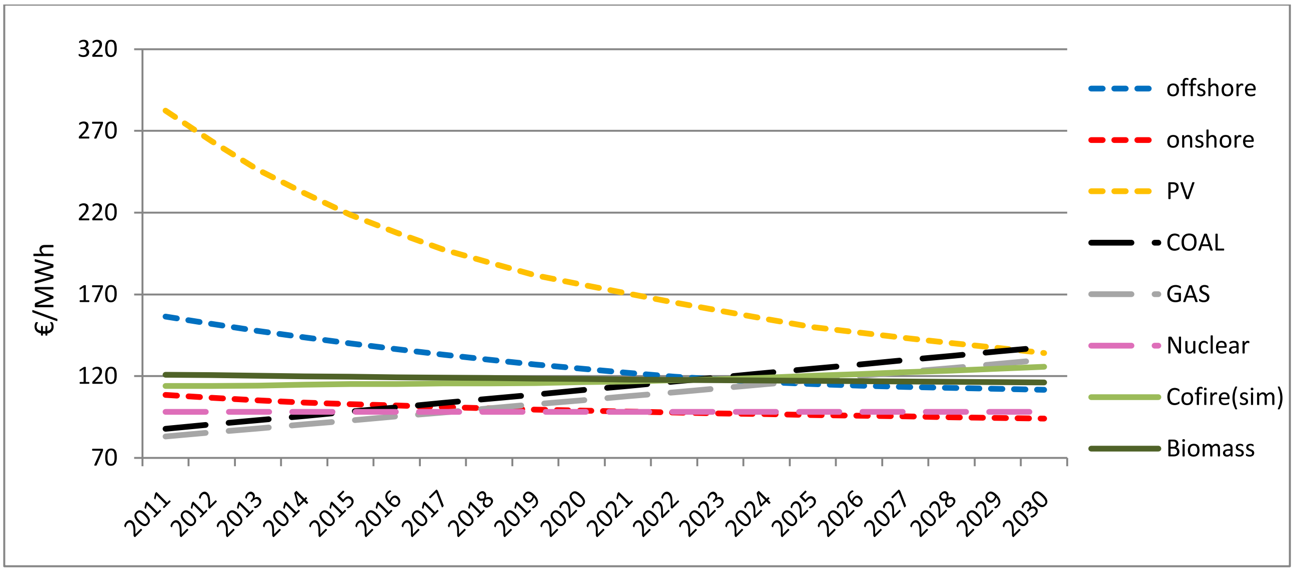

Figure 8: LCOE of new generation assets – optimistic pellet price scenario

3.1.3.3. Discussion

The three scenarios with stable load factors – 80% for both biomass technologies – confirm that the economic attractiveness of biomass technologies is highly sensitive to the expectations about the pellet price evolution. In the pessimistic pellet price scenario, the LCOE of biomass technologies is significantly higher than the LCOE of PV, coal and gas. Investing in biomass is moderately attractive in the standard pellet price scenario and even very attractive in the optimistic pellet price scenario. If pellet prices were to evolve as assumed in the standard or the pessimistic scenario, then biomass will roughly be as expensive as fossil-based technologies in the long run. From an investment perspective, policy measures to ensure a sufficient supply of biomass are of utmost importance to trigger significant investments in new biomass generation capacity. However, it should be pointed out that finding this cheap supply – considering the sustainability issues mentioned in the first chapter – will be far from easy. Policymakers should be cautious in promoting biomass overnight, without a clear sustainability framework.

3.1.4. Sensitivity analyses

3.1.4.1. Load factor

The expected growth of intermittent generation is likely to have a significant impact on the load factors of other generation technologies. Consequently, lower load factors will increase the capital cost per MWh and hence augment LCOEs (see equations 1-3). In order to calculate the total cost of non-intermittent technologies under these assumptions, we assume that load factors gradually decline along the period. The evolution of the load factors in our simulation is presented in Appendix B. In Table 2, we compare the LCOE in 2030 for the two load factor scenarios ('full' and 'reduced'). The intermittent technologies are not included in this table, but, as a benchmark, it is useful to mention that the LCOE of onshore wind (the cheapest technology) is estimated to be 94 €/MWh in 2030.

Table 2: LCOE (2030) in €/MWh of new generation assets with reduced load factors

Load Factor	Biomass P	Biomass S	Biomass O	Cofiring P	Cofiring S	Cofiring O	Coal	Gas	Nuclear
Full	188	132	116	162	134	126	138	130	98
Reduced	193	136	120	165	137	129	146	136	120

In general, the reduced load factors do not significantly impact the gap between biomass technologies and coal and gas. Only nuclear is subjected to a high impact under the conditions of the reduced load factor scenario. In fact, the LCOE of nuclear increases from 98 to 120 €/MWh, therefore the gap with the other non-intermittent technologies is reduced slightly. Nevertheless, it remains the most attractive non-intermittent technology.

The lower load factors obviously increase the 2030 LCOE-gap between wind and all the non-intermittent technologies. With the reduced load factor, the high pellet price scenario leads to a 100% biomass LCOE that is about double the LCOE of wind in 2030. When we compare the latter pellet price scenario to the LCOE of coal, we find a 'worst case' cost-disadvantage of biomass of some 32% (€ 193 vs. € 146). On the other hand, under the optimistic pellet price scenario with the reduced load factors, the LCOE of 100% biomass is only 20 € above the LCOE of wind onshore. With standard pellet prices, the 2030 cost gap of 100% biomass technologies with wind onshore increases from 35%, under the full load scenario, to 39%, under the reduced load scenario. In short, the reduced load factor scenario illustrates that the 2030 LCOE differences between biomass-based technologies and the other non-intermittent assets remain roughly the same, while wind onshore (the most competitive technologies) slightly increases its competitiveness against all the non-intermittent technologies.

3.1.4.2 Learning Rate

The presented results depend on many assumptions and have intrinsic limitations. As we assumed that future investment cost reductions depend on learning efforts, higher or lower learning rates are likely to influence our findings. Figure 9 illustrates the learning rate sensitivity of our results in the standard pellet price scenario with stable load factors. This figure projects the LCOE with the assumed learning rate (see Table 1) together with the alternative LCOE when we increased and reduced this learning rate by 2%.

Figure 9 shows that the variation in the learning rates mainly influences the LCOE of PV, offshore and onshore wind and biomass co-firing. Not surprisingly, the technologies with the biggest growth potential are more influenced by a change in the learning rate. For biomass co-firing, the difference in LCOE with the extreme levels of the learning rates is limited to some € 6/MWh. For PV technologies, a 2% change in the learning rate can result in a LCOE variation of € 15/MWh. Nuclear is not depicted in Figure 9 since it was assumed that, due to increasing safety measures, costs for nuclear plants would not decrease in the future. The learning effect is thus, according to us, not applicable to nuclear.

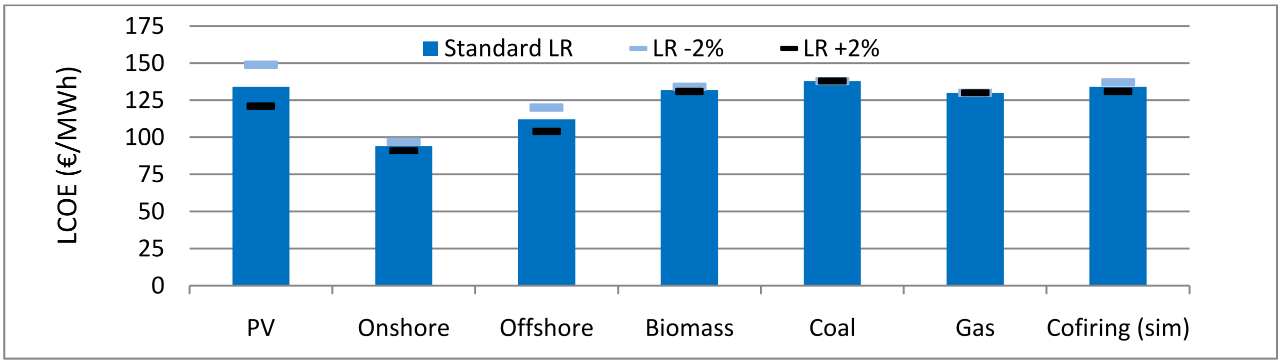

Figure 9: Learning rate sensitivity of 2030 LCOE (standard pellet price scenario)

3.1.4.3. Discount Rate

Another important parameter for the calculation of the LCOE is the discount rate. We used a 10% discount rate and present in Figure 10 alternative results with discount rates of 7 and 13%. As expected, the variation in the discount rate significantly impacts the results.

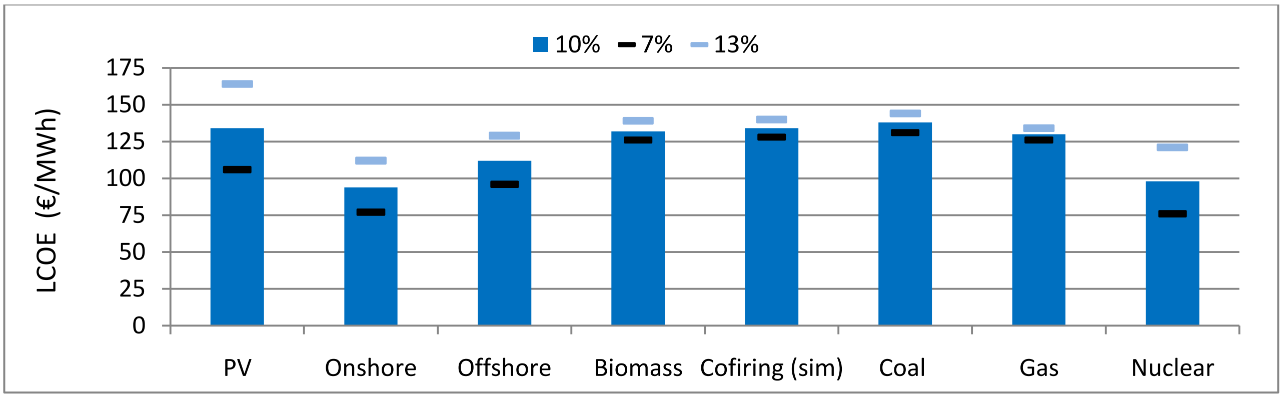

Figure 10: Discount rate sensitivity of 2030 LCOE (standard pellet price scenario)

A 3% variation in the discount rate markedly changes the LCOE-ranking in the standard scenario. With a 7% discount rate, nuclear technologies offer the lowest LCOE in 2030, followed by onshore wind, offshore wind, PV, 100% biomass and gas, biomass co-firing and coal. Lower discount rates increase the LCOE-gap between wind onshore and biomass technologies. A discount factor of 13% leads to a scenario where the gap between nuclear and wind technologies and biomass technologies is significantly reduced if compared both with the 7 and 10% discount rate scenarios. Higher discount factors reduce the LCOE-gap between wind and nuclear and biomass technologies.

3.1.5 Conclusion

From a LCOE-perspective, including a pragmatic carbon cost and a discount rate of 10%, we can conclude that today gas offers the least expensive generation opportunity with full production costs of around € 86 per MWh. The LCOE of biomass technologies – 100% biomass and 50% co-firing – is respectively some 48 and 38% higher than the LCOE of gas, which represents the 2012 benchmark. Without a CO_2 cost, biomass technologies are some 68% (100%) and 56% (50% co-fire) more expensive than gas. Onshore wind today (2012) has a LCOE slightly below our estimates for biomass technologies.

To explore the opportunity of biomass technologies from a stand-alone perspective – excluding all external costs for the electricity system at large – we compared three pellet price scenarios and two load factor scenarios for the period 2012-2030. Table 3 summarizes our findings. We compare both (100% and 50% co-fire) biomass technologies together – by averaging their LCOE in 2030 – to the LCOE of coal, gas and wind technologies in 2030. From Table 3 we can conclude that biomass technologies offer attractive investment opportunities from an LCOE-perspective in 2030. Only with high pellet prices, the LCOE of biomass technologies is 27-35% higher than the LCOE of coal and gas technologies. Compared to wind technologies, biomass faces a LCOE-disadvantage of 70 to 74% in 2030 under the pessimistic pellet price scenario.

With the standard pellet price scenario, biomass technologies are less expensive in 2030 than coal and as expensive as gas, and the LCOE-disadvantage to wind technologies is between 29 and 32%. With low pellet prices, biomass technologies have a significant LCOE-advantage over coal and gas technologies – between 9 and 15% – while wind technologies still offer a better investment opportunity.

Table 3: Competitiveness of biomass considering six scenarios in 2030

	Pessimistic pellet price	Standard pellet price	Optimistic pellet price
LCOE biomass / LCOE coal			
Full load	1.27	0.96	0.88
Reduced load	1.23	0.93	0.85
LCOE biomass / LCOE gas			
Full load	1.35	1.02	0.93
Reduced load	1.32	1.00	0.91
LCOE biomass / LCOE wind			
Full load	1.70	1.29	1.17
Reduced load	1.74	1.32	1.21

3.2. Economics from a system perspective

3.2.1. Introduction

LCOE analyses only provide information on production costs per MWh for different energy technologies on a ‘stand-alone’ basis. However, as all technologies need to be integrated into a system continuously balancing demand and supply, we need to consider the system dynamics and its boundary conditions. Further investments in some generation technologies can directly or indirectly increase total system costs, while investing in other technologies can eventually lead to lower system costs and thus generate system benefits. Also, it needs to be acknowledged that the impact of a given technology on system dynamics varies over time.

3.2.2. Towards a new system

In the electricity system of today, most production is generated with highly controllable assets which have guaranteed availability and predictable production. The production of electricity generally responds to changes in the electricity price. However, some technologies do not directly respond to price signals and continue to generate electricity, even when market prices are very low. For example, nuclear plants continue to produce irrespective of prices. Additionally, renewable electricity production is also insensitive to market prices, given the current incentive schemes in Europe (FIT or GSC).

The overview given in Table 4 is based on the assumption that in the world of tomorrow renewable production from wind, solar and biomass technologies will be much more important than today. As a consequence, assets with a limited availability and a limited predictability (wind and solar) need to be integrated. In this respect, biomass technologies offer the significant advantage of a high availability as well as a high predictability. On the other hand, biomass technologies face a resource scarcity just like fossil and nuclear technologies. If the share of renewable generation is high and nuclear capacity remains operational, the electricity system will contain many assets that do not respond to price signals, a situation which is not optimal from an economic perspective.

Prices have two dimensions; firstly, they reflect the economic cost of a commodity and secondly they provide information on the economic value of the produced commodities. Economic activities not responding to transparent and complete price information risk to create suboptimal allocations (e.g. excess production or shortages).

In the coming years, generation will become less responsive to price signals but will increasingly depend on weather patterns. In line with the limited predictability of weather patterns – especially on the medium and the long term – generation assets will also become increasingly unpredictable and their availability will decline.

Table 4: Comparison of electricity generation technologies from a system perspective

	Gas/Coal	Nuclear	Wind	Solar	Biomass	Hydro
Available when needed?	Yes	Yes	No	No	Yes	Yes
Predictable?	Yes	Yes	No	No	Yes	Yes
Input scarcity?	Yes	Yes	No	No	Yes	Variable
Sensitive to electricity price?	Yes	No, not flexible	No, subsidized	No, subsidized	No, subsidized	Yes
Current world	X	X				X
Future world	X	X	X	X	X	X

The above discussion indicates that biomass technologies can provide important system benefits. Only biomass and hydro plants offer the potential for renewable base-load and mid-merit/ intermediate generation. As it is very unlikely to develop a 100% renewable electricity system without renewable base-load and mid-merit production, biomass and hydro should play a pivotal role in energy transition scenarios. In the next decades, flexible biomass and hydro plants can also play a role in balancing the production from the intermittent renewable technologies.

The debate on the adaptation of the system to accommodate a growing intermittent production is far from settled. A more flexible system requires significant investments in transmission, distribution and smart grids to facilitate balancing and to accommodate changes in supply and demand. The need to foresee back-up and the long-term impact on loading factors and shedding should equally be considered given their potential impact on investment decisions. As biomass offers the potential for renewable generation without the typical system challenges of intermittent renewables, estimates of the system implications of additional intermittent generation can provide indications of the economic value of biomass in ‘high intermittency’ scenarios. In the next sections, we elaborate the system benefits of biomass starting from ‘high intermittency’ perspectives on future generation.

3.2.3. Back-up requirement

The typical availability of conventional plants is about 95%, however, on average only 4% of the total installed wind capacity in Spain and Germany has a comparable level of firmness (50). Around 17% of the total installed wind capacity has a level of firmness of 60%. This implies that wind’s firm contribution to available capacity of the system is around 10% (or less). The intermittent renewables should therefore be considered as energy sources but not as capacity suppliers (50).

The following example sheds light on the diverse needed back-up of wind and biomass technologies. When 10,000 MW wind capacity is installed in a system with a peak demand of 30,000 MW and 30,000 MW of fossil capacity, less than 1000 MW of this wind capacity is always available. To meet the peak demand of 30,000 MW in this system, 29,000 MW of the fossil capacity needs to be used. The development of 10,000 MW wind capacity does not make it possible to close down 10,000 MW of the available fossil capacity. According to Eurelectric (50), every MW of wind capacity generally requires a 1MW of back-up firm capacity to ensure 90% availability. Total capacity will evolve differently if we replace in this same system the 10,000 MW wind capacity with biomass capacity. As the biomass capacity is available at peak demand moments, it is indeed possible to close down fossil plants.

In Table 5, the back-up need per 100 MW generation assets is calculated starting from the typical “firm availability” for the NW European context. When assuming a 70% firm availability for biomass capacity, the addition of 100 MW biomass assets requires the provision of 30 MW back-up. In the basic system of Table 5, there are back-up needs for 3 generation technologies. The back-up needs for wind significantly exceed the back-up needs for biomass and for coal capacity. However, the total back-up for a generation portfolio is lower than the sum of back-up requirements per technology.

Table 5: Back-up needs per technology from a stand-alone perspective

100 MW Frontline	Firm availability	Back-up need	Back-up addition (relative to coal)
Coal	90%	10 MW	
Wind	10%	90 MW	80 MW
Biomass	70%	30 MW	20 MW

In Table 6, we present an example of how a future generation mix could look like in a NW-European region without hydro. Such a region could have a generation portfolio of 15,000 MW, of which 7000 MW is intermittent capacity (5000 MW wind + 2000 MW solar PV). In addition, there is 3000 MW biomass together with 2000 MW nuclear. The fossil capacity is limited to 3000 MW. The required back-up capacity depends on all the assets in the generation mix. Starting from base-load assets, the back-up need for 2000 MW nuclear capacity is around 100 MW. Adding 2000 MW gas will increase the total back-up needs to 250 MW, which is below 300 MW because the correlation of the non-availabilities of nuclear and gas assets is rather low. Adding 1000 MW coal further increases the back-up needs to 300 MW. The 3000 MW biomass capacity requires a back-up of 900 MW but 300 MW back-up is already established (in response to investments in nuclear, gas and coal capacity). As the correlation between the non-availabilities of biomass and the other assets is low, we do not need to increase the total back-up pool by 900 MW. We assume that an additional back-up investment of 700 MW is sufficient. With respect to the 5000 MW wind capacity, a back-up need of 4500 MW emerges from a stand-alone perspective. As already 1000 MW back-up assets are provided, total back-up provision will not increase by 4500 MW but by e.g. 3700 MW. Finally, the back-up needs for 2000 MW solar PV are 1900 MW from a stand-alone perspective but as already 4700 MW back-up is foreseen, a modest increase of the total back-up can be sufficient. In the example of Table 6 we end up with a total back-up need of 5000 MW or 33% of total installed capacity. With only nuclear, gas and coal capacity the back-up requirement would be only 6% of total installed capacity.

Table 6: Back-up needs for a portfolio of 15,000 MW with 7000 MW intermittent capacity

Frontline generation portfolio (15000 MW capacity)	Firm availability (capacity credit)	Back-up needed per asset	Cumulative Required back-up (nuclear → PV)	% of installed capacity	Increase of back-up need due to RES
2000 MW nuclear	95%	100 MW	100 MW	5%	
2000 MW gas	90%	200 MW	250 MW	6.25%	
1000 MW coal	90%	100 MW	300 MW	6 %	
3000 MW biomass	70%	900 MW	1000 MW	12.5%	+ 700 MW
5000 MW wind	10%	4500 MW	4700 MW	36%	+ 3700 MW
2000 MW solar PV	5%	1900 MW	5000 MW	33%	+ 300 MW
Total: 15000 MW		**7700 MW**	**5000 MW**		**+ 4700 MW**
Alternative portfolio with only changes in RES capacity (nuclear, gas and coal unchanged)					
6000 MW biomass	70%	1800 MW	1900 MW	17%	+ 1600 MW
3000 MW wind	10%	2700 MW	2900 MW	20%	+ 1000 MW
1000 MW solar PV	5%	950 MW	3100 MW	20%	+ 200 MW
Total: 15000 MW		**5850 MW**	**3100 MW**		**+ 2800 MW**

In an alternative portfolio in Table 6 (‘*Alternative portfolio with only changes in RES capacity*’) we increase total biomass capacity up to 6000 MW (+ 3000 MW) and lower the intermittent assets by 3000 MW. In this second example, the maximal generation on a given moment is identical to the maximal generation with the upper panel of Table 6 (under the assumption of strong wind and a high solar irradiation). With the alternative portfolio, total back-up needs are lower and the increase of back-up due to renewables is also much lower than in the upper panel. With 6000 MW of biomass, total back-up needs are ‘only’ 20% of total installed capacity. 3000 MW additional biomass capacity lowers total back-up needs by 1900 MW (while replacing 3000 MW intermittent capacity). In this example, trading 1 MW wind capacity for 1 MW biomass capacity lowers back-up needs by 0.6 MW per additional MW biomass.

From an environmental perspective, the back-up pool in the example of Table 6 should consist of very efficient assets. If not, the environmental benefits of a low-carbon generation system risk to be lowered by frequent use of inefficient high-carbon back-up plants. In principle, part of the back-up challenge could be met by integrating the regional market of Table 6 into a larger European market. In case of sufficient transmission and interconnection capacity, some of the needed back-up generation can be provided for by the excess production of wind electricity in neighboring countries. The ability to import electricity is sometimes presented as an alternative to the local provision of back-up capacity. The most comprehensive historical weather models however conclude that total wind and solar output in NW-E will be highly correlated and will not ‘average out’ over regions (51). In fact, when there is no wind in Belgium, there is probably no massive production of wind electricity in the Netherlands, Germany or France either.

As local back-up is essential to guarantee generation capacity, we can observe a massive expansion of total generation capacity in all scenarios with a high penetration of intermittent renewables in the next decades. As mentioned before, investments in additional wind capacity do not lead to equivalent reductions of fossil or nuclear capacity. When the UK would like to increase the share of intermittent renewables up to 50% by 2030, total installed capacity would have to increase from 80 GW today to 125 GW in 2030 (or increase by 56%). To further strongly increase the share of intermittent generation between 2030 and 2050, total generation capacity in the UK has to increase from 125 GW in 2030 to 230 GW in 2050. The latter increases by 85% between 2030 and 2050 will lead to a rise in electricity production of some 33% (52).

3.2.4. Load factors and shedding

In scenarios which combine a strong increase of installed capacity and only a slight – or perhaps no – increase in electricity demand, the use of capital can only decrease. The high penetration of intermittent renewables will lower the load factors of all other energy technologies, including low-carbon generation. It is to be expected that fossil and nuclear load factors will decrease. However, in extreme scenarios where wind capacity is maximized, the high penetration of intermittent renewables will even result in lower load factors for offshore wind (52).

In Table 7, we present projected load factors in several high intermittency scenarios developed by Pöyry for the UK (52). The results are striking; load factors for many technologies risk to become too low to trigger new investments as long as markets reward investors for produced MWh and not for the availability of capacity (irrespective of the use of this capacity). In the most extreme scenarios with the highest intermittent production, biomass plants – not a priority so far in the UK – will operate with load factors between 30 and 40%.

The high share of intermittent generation automatically results in underutilisation of other low-carbon assets. From an environmental perspective, the gains from replacing biomass by wind are marginal when compared to replacing an old fossil plant by wind. Shedding or shutting down efficient low-carbon generation can therefore be interpreted as indication of overinvestments in low-carbon capacity. In the high intermittency scenarios of Pöyry for the UK, shedding will become important by 2050. In both the High and Very High scenarios, shedding amounts to 7% of total electricity demand by 2050. In the Max scenario, shedding is 20% of total electricity demand and some 80 TWh of offshore wind generation is shed. Pöyry concludes that '*given our assumptions about flexibility and the renewable mix, the system struggles to accommodate renewable penetration above 80%* (52)'

Table 7: Load factors in high intermittency scenarios for the UK (52)

Scenario	% RES	LF offshore	LF biomass	LF nuclear	LF CCGT	LF peakers	Shedding (% of demand)	Shedding (TWh)
2010	4%	40%	65%	88%	50%	5%	-	-
High 2030	51%	40%	51%	88%	19%	0%	1%	6
High 2050	60%	40%	42%	75%	12%	5%	1%	6
Very High 2030	64%	40%	50%	81%	18%	0%	7%	38
Very High 2050	80%	40%	40%	62%	12%	3%	7%	41
Max 2050 or later	+90%	36%	30%	0%	19%	9%	20%	120

Massive investments in intermittent renewables can thus produce high external costs in terms of lower load factors, lower investment opportunities in other generation assets and significant shedding of low-carbon generation. These costs should be interpreted as uncompensated external costs: not the investors in intermittent generation but investors in other assests and society at large will have to bear these costs. The investors in intermittent generation will not compensate the owners of other generation assets for the reductions in load factors. Only in the extreme Max scenario with very significant shedding of offshore wind capacity, investors in intermittent generation will bear themselves part of load factor and shedding losses.

As a reduction of the load factor increases the LCOE of a technology, final consumers will face higher prices because of the increasing intermittency of the electricity system. According to models by Mott MacDonald, the levelized cost of nuclear and coal CCS would triple when the load factors would fall from 70% to 30%. For flexible gas plants, the levelized cost would only increase strongly once load factors are below 15% (53).

Investing in biomass plants can lead to lower shares of intermittent renewable and hence lower external load factor and shedding costs from high penetration rates of intermittent renewables.

However, investors in biomass capacity will not be rewarded for their contribution to lower external costs while investors in intermittent generation are not held responsible for these external costs.

3.2.5. System flexibility costs

In addition to the costs in the preceding paragraphs, we still have to consider the general cost of system flexibility in terms of new transmission and distribution capacity. To accommodate high intermittency, it is essential to move demand within the day and within longer periods. The cost to move demand should also be considered a part of the general cost of system flexibility. Modern energy systems have a significant potential for demand-side flexibility but there is a significant cost of harnessing this potential. Without smart grids, washing machines will not start working at the optimal moment and batteries of electric cars will not be charged at times with a high flexible supply but a low fixed demand. In the Pöyry analysis for the UK (52), it is assumed that movable demand can increase to about 15% of total demand in 2030 to become close to 200 TWh (one third of total demand in 2050). From a methodological perspective, it is challenging to calculate the full cost of moving demand in the electricity system. In order to connect a washing machine to the smart grid, some hardware changes need to be provided by the producers of washing machines and this brings a cost for users. Furthermore, strong price incentives need to be provided in order to stimulate users and producers to consider moving demand. These costs for final users are generally not included in estimates of system flexibility[3].

Table 8 presents the annualized costs of system flexibility in the UK for several 'high intermittency' scenarios developed by Pöyry (High 2030, High 2050, Very High 2030, Very High 2050 and Max). In this study, the cost of system flexibility is limited to the costs of transmission, distribution, interconnection, bulk storage, smart meters/grids and peaking capacity. Not surprisingly, the annualized cost of system flexibility is very sensitive to the share of intermittent renewables in total electricity generation. When comparing the 'High 2030' scenario and the 'Very High 2030' scenario, the results show that, amazingly, an additional capacity of 9 GW of wind and 22 GW of solar leads to an increase of annualized costs of system flexibility by £ 3.1 billion per year. By 2050, the annualized flexibility cost with 'High 2050' is £ 5.9 billion while 'Very High 2050' implies an annualized flexibility cost of £ 10 billion. This flexibility cost difference of £ 4.1 billion per year is the consequence of an additional wind capacity of 17 GW and a solar capacity investment of 35 GW.

Table 8: Intermittency scenarios for the UK and the annualized flexibility cost (AFC) in 2030 and 2050 (52)

Scenario	Cons (TWh)	Cap (GW)	% ren	Installed capacity (GW)						AFC (£bn/a)
				Wind on+off	Solar	Marine	Hydro + BM	CCGT	Peaker	
High 2030	409	125	51%	59	3	4	6	30	0	5.4
High 2050	551	171	60%	102	3	4	6	9	6	5.9
Very High 2030	409	158	64%	68	25	8	6	35	1	8.5
Very High 2050	551	230	80%	119	38	23	6	9	10	10.0
Max	611	298	+95%	191	38	31	6	13	21	16.6

Pöyry stresses that the high intermittency scenarios have not been selected from a cost-effectiveness perspective, as the main goal of the analysis was to find out whether high intermittency can be technically accommodated. It is thus possible to lower the high flexibility cost estimates in the left column of Table 8 by replacing wind and solar capacity with hydro and biomass capacity. The potential to increase hydro capacity is however limited in the UK. A strong increase of biomass is not integrated in the Pöyry scenarios as the goal was to assess high intermittency. Furthermore, the UK currently adopts a 'holding position' with respect to bio-energy at large. No significant increase

[3] To include the cost of all assets to move electricity demand would imply that the upfront investment cost of electric vehicles is part of the flexibility cost.

in bio-energy use is assumed in official documents such as Renewable Energy Review '*given concerns over sustainability and questions over the best long-term use for this limited resource'* (executive summary, p16, (54)).

In an effort to lower the flexibility cost of the system, we have to consider the replacement potential of biomass. With a load factor for biomass of 60% in 2030, 8 GW of additional biomass capacity can replace 16 GW wind capacity (with an average load factor of 30% for onshore together with offshore) or 9 GW wind and 21 GW solar (LF 10%). With a load factor of 75% for biomass plants in 2030, much more intermittent capacity can be replaced. The difference between High 2030 and Very High 2030 also includes more tidal energy capacity (+4 GW), more CCGT capacity (+5 GW) and more peaking capacity (+1 GW). As especially the CCGT and peaking capacity is related to the increasing intermittency between High 2030 and Very High 2030, 8 GW additional biomass capacity can partly replace the additional CCGT and peaking needs in Very High 2030.

Although the comparison is simplified and not complete, we can conclude that the investment in 8 GW biomass capacities by 2030 can prevent most of the projected increase of annualized flexibility cost in the shift from the High 2030 scenario to the Very High 2030 scenario. Based on the Pöyry assessment for the UK (52), investing in 8 GW of biomass capacity avoids an increase of system flexibility costs close to £ 3 billion per year. By 2050, more biomass capacity can be developed but the (much) lower load factors will make it difficult to replace much more wind and solar capacity.

Summarized, in this framework with an electricity system of 400 TWh we have to distinguish two pathways to a high share of renewable generation (50 to 60% share of renewable in generation): the massive deployment of intermittent generation will lead to high system flexibility costs while the alternative with a lower – but still very important – deployment of intermittent renewables is complemented by investments in additional biomass capacity. We estimate that the annual flexibility cost from mainly intermittent renewables can be reduced by roughly one third (£ 3.1 bn / £ 8.5 bn) when intermittent capacity is lowered by 15% in response to additional biomass investments.

It is important to realize that these findings are mainly indicative and based on the rather radical deployment scenarios for the UK (52). These scenarios should however not be interpreted as unique 'island' scenarios since increased interconnection with Ireland, NW-E and Norway is included, as well as powerful active demand management systems – that move up to 30% of total demand – and bulk storage possibilities.

3.3. Conclusions

In this electricity system overview we focused on back-up needs, load factors, shedding, cost-efficient RES targets and the general system flexibility costs. We can identify that biomass capacity offers several important benefits. Most of them will however only become visible in the next decades – assuming that the share of intermittent renewables will indeed strongly increase – although there are also benefits to be experienced as of today;

1. In high intermittency scenarios, biomass capacity can significantly lower total back-up needs; in our example, trading 1 MW wind capacity for 1 MW biomass capacity lowers back-up needs by 0.6 MW per additional MW biomass
2. In high intermittency scenarios, biomass capacity can limit the projected reduction of load factors
3. In high intermittency scenarios, biomass capacity can avoid massive shedding of low-carbon generation (up to 30% of demand in extreme scenarios)
4. In high intermittency scenarios, massive deployment of biomass capacity can lower system flexibility costs by 30%

From a societal perspective, additional biomass capacity lowers the system investment needs. Also, biomass capacity limits the expected price increases from a system that becomes more capital-intensive but has lower load factors and requires increasing shedding of efficient low-carbon generation. For the final consumer, the electricity bill will increase with every additional euro invested in new assets. Although we can only estimate the system benefits of additional biomass capacity, it is obvious that all these positive externalities from biomass use are currently not considered in our policy frameworks. In the market configuration of today, there are no incentives to consider the external cost and benefits of generation technologies. The debate on externalities is much wider than the conventional focus on negative externalities such as pollution and CO_2 costs. Renewable energy frameworks are dominated by flat production incentives for all generation technologies irrespective of their system consequences. In optimal incentive frameworks targeting high shares of renewable energy sources (RES), assets with the potential to significantly limit system costs should be favored over assets that not only generate renewable electricity but high system costs as well.

From a public policy perspective, the existence of positive system externalities typically leads to underinvestments in the assets producing these externalities. To correct for negative externalities, the underlying activity should be supported, leading to incentive schemes that internalize the external benefits for investors. In the context of support for biomass assets, an optimal support framework should internalize the system benefits of biomass to trigger additional investments in biomass capacity.

4. Conclusion

Biomass electricity production has the potential to become a very important piece in the energy puzzle of tomorrow. It comes with many interesting benefits which are currently underestimated and thus unrewarded. Some of these are already visible; others will become prominent in coming decades. Today, biomass can be used as a low-carbon source for electricity, and can help member states in the EU to reach their 20/20/20 targets efficiently. In the world of tomorrow, biomass power plants can become a crucial part of the electricity mix, as a grid stabilizer and a renewable source of back-up power supply. This is especially true for NW-Europe, since this region does not have sufficient hydro capacity to balance weather dependent, intermittent renewables, such as solar and wind.

Society as a whole can strongly benefit from the use of biomass for electricity production; however, in order to reach this goal, some conditions need to be met. The primary condition is that sufficient supplies of sustainably produced biomass need to be available. Failing to meet this condition will result in either high, non-competitive electricity production costs or in producing electricity with a high carbon footprint, or, in the worst case, both. This can be avoided by investing in both sustainable forest management – to ensure the sustainability – and reliable biomass supply chains – to avoid shortages. Since the likelihood of reaching the 2°C target has only decreased in recent years, these investments should start as soon as possible.

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Appendix A

In Table A. 1, we present an overview of the LCOE for new investments in different generation technologies in 2011/2012. The cost figures in this table should be interpreted as averages for the period 2011-2012. We opted for average cost figures to avoid that our results strongly depend on temporary price movements. Table A. 1 is based on the international literature while the load factors are set in line with the NW European context. We added a CO_2 cost of 30 US$ per ton (or € 23/tCO_2) to reflect the cost of climate policy measures for electricity producers. This CO_2 cost is above the ETS price of January 2011, but is an adequate illustration of the resource cost of climate measures. The total cost per technology in €/MWh should be interpreted as the average cost (in present value) per MWh for an investor who invests today in a particular technology and uses a discount factor of 10%.

In Table A. 1, we included two biomass technologies. The first – 100% Biomass – is a dedicated biomass plant of significant scale (>300 MW) which only burns wood pellets. As biomass is mostly co-fired in coal plants with co-firing rates between 5 and 10%, we also wanted to include co-firing in our overview. Today, an investor will however not build a new coal plant with the purpose of 5% or 10% biomass co-firing. A typical co-firing plant therefore does not fit in the LCOE methodology for new projects. To accommodate the co-firing technology to the LCOE philosophy, we assume that co-firing technologies evolve in way that 50% co-firing of biomass becomes possible in the next years. As this 50% co-firing does not yet exist, we refer to it as Cofire(sim) in our simulations. We want to emphasize that the latter plant should not be confused to the co-firing practice of today in most countries. In our approach, we estimate the investment cost of a 50% co-firing plant to be around € 2300 per kW and use this value as a starting position in our analysis. From an investment perspective, flexible coal plants with the ability of 50% biomass co-firing offer the benefit of flexible generation in response to the relative prices of coal and pellets. The insurance against feedstock price spikes can compensate the higher investment cost for this type of plant.

Once the CO_2 cost is included, Table A. 1 shows that coal and gas offer the least expensive generation opportunities with production cost of some € 100 per MWh. The LCOE with biomass technologies is some 35% above the LCOE with coal and gas technologies. Without a CO_2 cost, biomass technologies are some 60% more expensive than coal and gas technologies. Onshore wind technologies have a LCOE that is close to the estimates for biomass technologies. Offshore wind is some 20% more expensive than onshore wind while the LCOE of PV is still prohibitive. The LCOE of nuclear technologies is between the LCOE of biomass and the LCOA of gas and coal technologies. We opted for a high investment cost for nuclear capacity in response to post-Fukushima concerns and cost overruns for new nuclear in France and Finland[4].

[4] http://www.guardian.co.uk/environment/damian-carrington-blog/2011/jul/22/nuclear-power-cost-delay-edf and http://www.nytimes.com/2009/05/29/business/energy-environment/29nuke.html?pagewanted=al

	World Capacity	Lifespan	Load Factor	Learning Rate	Investment. Cost	O&M	Feedstock Cost	Carbon Cost	Total Costs
	GW	Years	%	%	€/kW	€/MWh	€/MWh	€/MWh	€/MWh
PV	61[a,b]	25[o]	12[f,e,k]	15[h,i]	2600[b]	10[f]	0	0	264[a]
Wind onshore	286[c,g]	25[e]	25[f,e,k]	8[h,i]	1800[j]	18[j]	0	0	107[a]
Wind offshore	5[c]	20[e]	35[f,e]	8-10[h,i]	3300[f,j]	30[j,f]	0	0	152[a]
100% Biomass	64[a,c]	25[f]	80[f]	7[a,i]	2100[f,m]	15[f]	73[l,a]	0	122[a]
Co-firing (sim)	3[a]	30[f]	80[f]	8[a,f]	2300[f]	15[f]	54[a]	11.5[e,a]	115[a]
Coal	1513[c,d]	35[f]	80[f,k]	7[h]	1700[d,e,f]	7[f,e,a]	30[a]	23[e]	90[a]
Gas	1308[c,d]	30[e]	70[f,k]	10[h,i]	900[d,e,f]	5[f,e,a]	50[a]	10[e]	86[a]
Nuclear	388[c,d,n]	50	85[e,k,n]	0[i]	5700[e,p,q]	13[e,a]	8[e,a]	0	98[a]

Table A. 1: LCOE of new generation technologies in 2011-2012 (first quarter) with starting assumptions for simulation up to 2030

a) our calculation; b) EPIA, 2010 (55); c) REN21, 2011 (1); d) IEA ETSAP, 2010 (56); e) IEA, 2010 (57); f) discussion with the industry; g) EWEA, 2011 (58); h) Weiss et al., 2010 (49); i) Neij, 2008 (42); j) IEA, 2009 (59); k) Lenzen, 2010 (60); l) Sikkema et al., 2011 (61); m) Faaij, 2006 (62); n) World Nuclear Association (63); o) Laleman et al., 2011. (30); p) NY times (64); q) Guardian (65)

Appendix B

In Table B. 1, the projected evolution of fuel and carbon costs is summarized. In our simulations, we also considered the impact of lower load factors for non-intermittent generation technologies in response to an increasing share of intermittent generation. The two left columns of Table B. 1 present the load factors of Table A. 1 used in the 'stable load factor' scenarios and the reduced load factors used in the 'reduced load factor' scenarios (see further). The three fuel cost levels for biomass technologies by 2030 in Table B. 1 refer to the three pellet price scenarios; optimistic (O), standard (S) and pessimistic (P).

	2010 Fuel Cost	2030 Fuel Cost	2010 CO_2 Price	2030 CO_2 Price	2030 Stable LF	2030 Reduced
	€/MWh	€/MWh	€/MWh	€/MWh	%	%
100% Biomass	73	73 - 89 - 145 (O – S – P)	0	0	80	70
Cofiring(Sim)	54	66 - 75 - 103 (O – S – P)	11.5	23	80	70
Coal	30	60	23	46	80	60
Gas	50	90	10	20	70	50
Nuclear	8	6	0	0	85	65

Table B. 1 Fuel and CO_2 price assumptions (2010-2030) per technology

The fuel costs in Table B. 1 can be considered as minimal marginal production costs for the considered generation technologies. Market prices below these minimal marginal production costs will produce marginal losses. The rather low market prices in NW Europe since 2008 significantly complicate investment decisions in new generation technologies with high marginal production costs such as biomass and gas technologies.

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